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BEFORE THE ARIZONA CORPORATION COMMISSION

Arizona Corporation Commission
DOCKETED

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IN THE MATTER OF THE COMPETITION IN THE PROVISION OF ELECTRIC SERVICES THROUGHOUT THE STATE OF ARIZONA.

DOCKET NO. U-0000-94-165

NOTICE OF FILING

Staff of the Arizona Corporation Commission hereby files a report submitted by The Electric System Reliability and Safety Working Group, in the above-captioned matter.

RESPECTFULLY SUBMITTED this 18th day of November, 1997.

ARIZONA CORPORATION COMMISSION

By: Christopher C. Kempley

Christopher C. Kempley
Acting Chief Counsel
Legal Division
1200 West Washington Street
Phoenix, Arizona 85007
(602) 542-3402

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REPORT TO THE

ARIZONA CORPORATION COMMISSION

IN THE MATTER OF THE COMPETITION IN THE PROVISION OF ELECTRIC SERVICE THROUGHOUT THE STATE OF ARIZONA DOCKET NO. RE-0000C-94-165

Submitted By

The Electric System Reliability and Safety Working Group

November 17, 1997

ARIZONA CORPORATION COMMISSION

November 18, 1997

To The Commissioners:

On October 10, 1996, the Commission, in Decision No. 59869, ordered Staff to establish the Electric System Reliability and Safety Working Group. Decision No. 59943, issued by the Commission on December 26, 1996, contained rules ("Rules") providing for a phased-in transition to retail electric competition in Arizona, beginning on January 1, 1999. The Rules include a requirement that the Working Group report to the Commission regularly and make recommendations regarding improvements to reliability or safety.

Over the past year, the Working Group has come to agreement on a series of conclusions and recommendations. The most significant conclusion is: "The Working Group has not identified any potential impacts of competition which cannot be sufficiently addressed to enable transmission system reliability to be maintained at current levels." The Working Group has completed its evaluation of 31 reliability- related activities, including specific recommendations under two possible scenarios: with an Independent System Operator (ISO) and without an ISO. Finally, the Working Group has identified a list of proposed agreements and protocols that need to be developed as the next priority for the Working Group.

Respectfully submitted,

Ray T. Williamson

Ray T. Williamson
Chief, Economics and Research
Working Group Leader
Arizona Corporation Commission

RTW

APPENDICES:

INTRODUCTION

The Electric System Reliability and Safety Working Group was established by the Commission on October 10, 1996, in Decision No. 59689. The Commission adopted rules to introduce retail electric competition on December 26, 1996 in Decision No. 59943. The purpose of this report is to summarize key general conclusions and to recommend to the Commission practices, policies, and activities to ensure continuing reliability and safety in a retail open access environment.

The Reliability and Safety Working Group has completed a review of 31 "Reliability-Related Activities" reported in the "ACC Interim Report of the Electric System Reliability and Safety Working Group" dated December 31, 1996 (Docket No.RE-0000C-94-165). Table 1 of the Interim Report lists 31 reliability related activities which support standards and protocols used to plan, design, construct, maintain and operate today's electric energy production and delivery system. These reliability-related activities were listed chronologically, based upon application in the day-to-day functions of a vertically integrated utility company.

The reliability-related activities can be grouped into eight broad categories (Appendix B):

I. Load Forecasting
II. Resource Planning
III. Delivery System Planning
IV. Control Area Services
V. System Maintenance
VI. Resource Operations
VII. Transmission Operations
VIII. Metering

A four-part analysis was completed on each of the reliability-related activities (Section II of this report). The analysis consisted of:

1. What Utilities Do Today
2. Potential Impacts of Competition
3. Recommendations
4. Enforcement

Further, the Recommendations and Enforcement analyses were reviewed under two scenarios: 1) with an Independent System Operator (ISO), and 2) without an ISO. Concurrent to the Reliability and Safety Working Group's activity, a Southwest regional group of interested entities signed a memorandum of understanding to investigate the feasibility of forming an ISO for the region. The entities met from April to October 1997 under the name of Desert Southwest Transmission And Reliability Operator (Desert STAR). The Desert STAR Work Groups have completed the Phase I Feasibility Study and continue to evaluate formation of an ISO.

Part one of this report contains general conclusions and recommendations of the Working Group. The Working Group concluded that in order to ensure reliability in a competitive environment, it is essential that several new agreements and protocols be developed to govern the interaction of participants in the market for electric service. The areas that require new agreements and protocols are listed and described. However, the details of implementing these new agreements and protocols have yet to be worked out. The Working Group has decided that the development of these details will be its next task.

Part two of this report contains a discussion of the thirty-one reliability-related activities that utilities currently perform. The introduction of retail competition may significantly change how these activities are performed.

I. CONCLUSIONS AND RECOMMENDATIONS

A. General Conclusions

1. The Working Group has not identified any potential impacts of competition which cannot be sufficiently addressed to enable transmission system reliability to be maintained at current levels.

2. In a retail access environment, generation will be supplied by the competitive market. This will result in no single entity having responsibility for ensuring adequacy of supply for a given territory or region. Electric service providers (ESPs) will be responsible for short-term supply planning for their customers. In the long run, competitive providers will respond to the price signals and other market information to make investment decisions in new energy resources.

3. The formation of a multi-state Independent System Operator (ISO) -- with responsibility for security coordination, scheduling, OASIS, and congestion management -- would be a means to facilitate implementation of retail electric competition while maintaining transmission system reliability.

4. Desert STAR, the ISO under consideration in the Southwest, has completed its feasibility study, which provides a framework to meet transmission reliability needs in a competitive environment. However, no binding commitments have been made to ensure its formation. Even with a full commitment to go forward, Desert STAR will not be operational on January 1, 1999, the starting date of retail access in Arizona.

5. In the absence of an independent transmission oversight structure, transmission system reliability can be maintained in a retail access environment through existing security coordinator and Control Area guidelines if a number of agreements are put in place to facilitate coordination among control areas and market participants. In addition, certain protocols should be established

to ensure that access to the grid is non-discriminatory for retail customers.

6. In the absence of an independent transmission oversight structure, retail transmission service will be under the immediate control of transmission owning utilities. Under FERC Order 888, transmission owning utilities are required to separate transmission and merchant functions to ensure non-discriminatory wholesale access. To achieve more independent oversight, it may be beneficial to form an "Independent Transmission Operator" (ITO) to perform certain functions in support of non-discriminatory retail access, including scheduling administration and operation of the OASIS. While these functions fall short of full ISO responsibilities, they may be sufficient to support retail access in the early stages, pending evaluation of other alternatives. The ITO should be designed to be operational by January 1, 1999.

B. General Recommendations:

1. To implement retail direct access, at a minimum, agreements dealing with the following operating/coordination issues should be developed:

- Scheduling for retail service
- Energy schedule curtailments for transmission capacity restrictions
- Retail transmission service terms and conditions
- Energy imbalance service -- pricing, terms, and conditions
- Acquisition of reserves by load serving entities providing firm service and generator contingency plans and operating agreements
- Generator interconnection agreements -- roles, authority, and responsibilities
- Ancillary services tariff to support retail access transactions -- regulation and frequency response, voltage control from generation resources, reserve service
- Operation, pricing, and cost allocation for "must-run" units

(See Appendices C & D for descriptions of proposed agreements and development schedule.)

2. To implement retail access, at a minimum, protocols dealing with the following operating/coordination issues should be developed:

- Short-term load forecasting
- Long-term load forecasting
- Available Transfer Capability (ATC) calculation
- Generator maintenance scheduling
- Public posting of transmission maintenance schedule
- Coordination in performing transmission operating studies
- Posting of real time market information for transmission and ancillary services supporting retail access transactions (OASIS)

(See Appendices C & D for descriptions of proposed protocols and development schedule.)

3. The concepts and functionality of an Independent Transmission Operator (ITO) should be explored further.

II. RELIABILITY-RELATED ACTIVITIES

This section contains a discussion of thirty-one reliability-related activities that utilities currently perform and that will be affected by the introduction of retail competition. The discussion starts with activities that are relevant in the long run, such as long range forecasting and planning. The discussion then moves to activities with tighter time frames, such as short term planning, and ends with activities that are relevant in real-time, such as disturbance response.

1. Long Range Load Forecasting

A. What Utilities Do Today

Utilities use models to forecast load growth in their service territories. WSCC aggregates for subregions and for the entire WSCC.

B. Potential Impact of Competition

Market participants will perform their own market analysis.

Aggregation of load forecasts requires greater coordination due to the increased number of load-serving entities.

C. Recommendations

With an ISO: Utility Distribution Companies should be assigned the responsibility to produce and publish long-term load forecasts for their respective distribution territories. This information can be made available as a public database for the review of regulators, suppliers, and customers. The ISO should consolidate the forecasts into one forecast for the area. Standards and protocols on information sharing need to be developed, including the information pertaining to transmission-interconnected customers.

Without an ISO: Utility Distribution Companies should be assigned the responsibility to produce and publish long-term load forecasts for their respective distribution territories. This information can be made available as a public database for the review of regulators, suppliers, and customers. SWRTA and/or WSCC should consolidate the forecasts into one forecast for the area. Standards and protocols on information sharing need to be developed, including the information pertaining to transmission-interconnected customers.

D. Enforcement

With an ISO:

Primary Opinion:

State-regulated Utility Distribution Companies should be required by the ACC to follow the above recommendations. Non-state-regulated Utility Distribution Companies should be required to follow the above recommendations as a condition of an inter-governmental agreement authorizing participation in retail access under the ACC Rule.

Alternate Opinion:

WSCC, FERC, and/or ISO should enforce.

Without an ISO:

Primary Opinion:

State-regulated Utility Distribution Companies should be required by the ACC to follow the above recommendations. Non-state-regulated Utility Distribution Companies should be required to follow the above recommendations as a condition of an inter-governmental agreement authorizing participation in retail access under the ACC Rule.

Alternate Opinion:

WSCC, FERC, and/or Control Area should enforce.

2. Generation Planning

A. What Utilities Do Today

Utilities use load forecasts to plan and build sufficient generating capacity both to meet loads and to provide necessary ancillary services to secure the system allowing for planned and forced generator outages and other uncertainties.

B. Potential Impact of Competition

Generation planning to meet load becomes market driven.

Load responsibilities become defined by contracts.

There is a generation planning component that belongs to the ancillary service provider.

C. Recommendations

With an ISO: Generation planning should be conducted privately by individual generation providers in response to market forces. At some reasonable amount of time prior to interconnection, entities planning to bring on new generation will need to inform the ISO and coordinate with the ISO pursuant to FERC Orders 888 & 888a and 889 & 889a.

Without an ISO: Generation planning should be conducted privately by individual generation providers in response to market forces. At some reasonable amount of time prior to interconnection, entities planning to bring on new generation will need to inform the Control Area Operator and coordinate with the Control Area Operator pursuant to FERC Orders 888 & 888a and 889 & 889a.

D. Enforcement

With an ISO: Generation providers, which fail to plan appropriately, will be "disciplined" in the market. Failure to meet notice requirements recommended above could result in delayed interconnection dates. This activity is no longer under ACC jurisdiction.

Without an ISO: Generation providers, which fail to plan appropriately, will be "disciplined" in the market. Failure to meet notice requirements recommended above could result in delayed interconnection dates. This activity is no longer under ACC jurisdiction.

3. Installed Adequate Reserves

A. What Utilities Do Today

Utilities use specific criteria for required reserve margin above peak load to ensure reliable power supply.

B. Potential Impact of Competition

Becomes market driven.

Responsibility for providing installed reserves will belong to the various load-serving entities.

C. Recommendations

With an ISO: It should be a requirement of interconnection that all load-serving entities obtain reserves necessary to meet WSCC (or ACC) standards. This requirement would be reflected in the amount of capacity-backed sales that a load-serving entity would be permitted to have scheduled. The ISO (or the ACC) should be responsible for ensuring that an adequate portion of installed generation was dedicated to providing reserves. The ISO and or the Utility Distribution Company should have real-time control of delivery to customer loads that desire non-firm contracts.

Without an ISO: It should be a requirement of interconnection that all load-serving entities obtain reserves necessary to meet WSCC (or ACC) standards. This requirement would be reflected in the amount of capacity-backed sales that a load-serving entity would be permitted to have scheduled. The ACC should be responsible for ensuring that an adequate portion of installed generation was dedicated to providing reserves. Control Areas should have real-time control of delivery to customer loads that desire non-firm contracts.

D. Enforcement

With an ISO: The enforcement (penalties/sanctions) could occur, in part, via the ACC certification process through which load-serving entities would be permitted to have scheduled only a certified amount of capacity-backed transactions, corresponding to the portion of their peak load backed by installed adequate reserves.

Without an ISO: The enforcement (penalties/sanctions) could occur, in part, via the ACC certification process through which load-serving entities would be permitted to have scheduled only a certified amount of capacity-backed transactions, corresponding to the portion of their peak load backed by installed adequate reserves.

4. Regional Transmission Planning

A. What Utilities Do Today

All WSCC member utilities owning transmission are involved in planning and reliability committees, which perform technical studies and joint planning to ensure reliability of the interconnected electric power system.

B. Potential Impact of Competition

Planning will be more dynamic.

The transmission system will not be used in the same way.

Incentives to build will change.

C. Recommendations

With an ISO: Planning should be conducted jointly between individual transmission-owning entities and the ISO, in coordination with SWRTA and WSCC, and should include all interested stakeholders. Any stakeholder willing to fund transmission expansion should be permitted to do so and to obtain transmission capacity rights thereby (as is proposed to be permissible under Desert STAR).

Without an ISO: Planning activity should be coordinated through SWRTA and WSCC and should include all interested stakeholders in the discussion of regional and subregional planning issues. Any stakeholder willing to fund transmission expansion should be permitted to do so and to obtain transmission capacity rights thereby.

D. Enforcement

With an ISO: NERC and WSCC criteria in addition to SWRTA.

Without an ISO: NERC and WSCC criteria in addition to SWRTA.

5. Subregional Transmission Planning

A. What Utilities Do Today

Arizona utilities participate in subregional planning and technical studies to ensure reliability of the transmission system in Arizona, New Mexico, California and Southern Nevada.

B. Potential Impact of Competition

Planning will be more dynamic.

Incentive to build will change.

C. Recommendations

With an ISO: The ISO, in coordination with SWRTA and WSCC, should have primary responsibility for this level of planning activity and should include all interested stakeholders in the discussion of regional and subregional transmission planning issues. Any stakeholder willing to fund transmission expansion should be permitted to do so and to obtain transmission capacity rights thereby (as is proposed to be permissible under Desert STAR).

Without an ISO: Planning activity should be coordinated through SWRTA and WSCC and should include all interested stakeholders in the discussion of regional and subregional planning issues. Any stakeholder willing to fund transmission expansion should be permitted to do so and to obtain transmission capacity rights thereby.

D. Enforcement

With an ISO: NERC and WSCC criteria in addition to SWRTA.

Without an ISO: NERC and WSCC criteria in addition to SWRTA.

6. Individual Utility Transmission Planning

A. What Utilities Do Today

Each utility plans and establishes operating limits for its transmission facilities. Technical studies are performed using specific criteria for equipment loading, voltages, and system stability under normal conditions and for equipment that is out of service.

B. Potential Impact of Competition

Incentive to build will change.

Planning will be more dynamic.

C. Recommendations

With an ISO: Planning should be conducted jointly between the individual transmission-owning entity and the ISO, in coordination with SWRTA and WSCC and should include all interested stakeholders. Any stakeholder willing to fund transmission expansion should be permitted to do so and to obtain transmission capacity rights thereby (as is proposed to be permissible under Desert STAR).

Without an ISO: Planning should be conducted in coordination with SWRTA and WSCC and should include all interested stakeholders. Any stakeholder willing to fund transmission expansion should be permitted to do so and to obtain transmission rights thereby.

D. Enforcement

With an ISO: NERC and WSCC criteria in addition to SWRTA.

Without an ISO: NERC and WSCC criteria in addition to SWRTA.

7. Distribution Planning

A. What Utilities Do Today

Each utility improves its local distribution system based on anticipated local growth. This provides appropriate reliability at the individual customer level.

B. Potential Impact of Competition

Assuming the distribution system is not open to competition, no change.

C. Recommendations

With an ISO: No change.

Without an ISO: No change.

D. Enforcement

With an ISO: No change.

Without an ISO: No change.

8. Generation Maintenance

A. What Utilities Do Today

Utilities perform generating unit maintenance based on a manufacturer's specifications and maintenance activity is coordinated for reliability purposes.

B. Potential Impact of Competition

Coordination among generation providers will be supplemented with increased coordination between generation providers and the transmission providers.

C. Recommendations

With ISO: The generation provider should be responsible for maintaining the units it operates pursuant to the standards for interconnection developed by the ISO. Maintenance schedules will be developed by generation providers based primarily on economic considerations but should be coordinated with the ISO and are subject to reliability constraints.

Without ISO: The generation provider should be responsible for maintaining the units it operates pursuant to the standards developed by the control area. Maintenance schedules will be developed by generation providers based primarily on economic considerations but should be coordinated with the area Security Coordinator and are subject to reliability constraints.

D. Enforcement

With ISO: Economic incentives overseen by the ISO should be provided so that performance based maintenance is performed to maximize availability of generating units for reliability.

Without ISO: Economic incentives overseen by the ACC or NERC/WSCC should be provided so that performance based maintenance is performed to maximize availability of generating units for reliability.

9. Transmission Equipment and Right of Way Maintenance

A. What Utilities Do Today

All utilities perform routine transmission equipment and right-of-way maintenance. Major maintenance is coordinated with generation to minimize total system costs. Maintenance frequency is determined by manufacturers' recommendations, and utility experience obtained from historical tracking of equipment trouble and outages.

B. Potential Impact of Competition

Transmission facilities owners will be driven by different economic incentives making coordination more challenging.

C. Recommendations

With ISO: The transmission facilities owners should remain responsible for adequate equipment and right of way maintenance and the cost will be recovered in the transmission rates. The ISO, in conjunction with the transmission facilities owners, should develop reliability performance criteria for transmission equipment. The transmission facilities owners would then use the criteria to develop and implement the maintenance plan required to meet or exceed that performance level. The ISO will coordinate and have final authority over planned equipment outages necessary for the maintenance.

Without ISO: The transmission facilities owners should remain responsible for adequate equipment and right of way maintenance and the cost will be recovered in the transmission rates. An outage coordinator, in conjunction with the transmission facilities owners, should develop reliability performance criteria for transmission equipment. The transmission facilities owners would then use the criteria to develop and implement the maintenance plan required to meet or exceed that performance level. An outage coordinator will coordinate and have final authority over planned equipment outages necessary for maintenance.

D. Enforcement

With ISO: The ISO will be subject to sanctions for not meeting NERC and WSCC operating criteria. The transmission provider will be subject to sanctions for not meeting performance criteria.

Without ISO: The transmission provider will be subject to sanctions for not meeting NERC and WSCC operating criteria.

10. Coordination of Transmission and Generation Maintenance Activities

A. What Utilities Do Today

Arizona utilities coordinate generation and transmission equipment maintenance activities with each other and other utilities in New Mexico, California, and Southern Nevada.

B. Potential Impact of Competition

Generation and transmission facilities owners will be driven by different economic incentives making coordination more challenging.

C. Recommendations

With ISO: The ISO should be responsible for the coordination of transmission and generation maintenance activities. Generation maintenance schedules should be filed with the ISO in advance, so that the ISO can ensure that necessary resources are available to maintain system reliability. The ISO will have final authority over planned outage schedules. All transmission and generation providers will be responsible for fully cooperating with these coordination efforts. The ISO should have a protocol for informing/signaling generation providers that adjustments are necessary, an activity which can be incorporated into the ISO's oversight of operating reserves.

Without ISO: An outage coordinator should be responsible for the coordination of transmission and generation maintenance activities. Generation maintenance schedules should be filed with the Security Coordinator in advance, so that the Security Coordinator can ensure that necessary resources are available to maintain system reliability. An outage coordinator will have final authority over planned outage schedules. All transmission and generation providers will be responsible for fully cooperating with these coordination efforts. The Security Coordinator should have a protocol for informing/signaling generation providers that adjustments are necessary, an activity which can be incorporated into the Security Coordinator's oversight of operating reserves.

D. Enforcement

With ISO: The ISO and all transmission and generation providers will be subject to sanctions for not meeting NERC and WSCC operating criteria. Frequent forums such as operating committee meetings should be held to discuss lessons learned and maximize successful coordination.

Without ISO: Control Area Operators and generation providers will be subject to sanctions for not meeting NERC and WSCC operating criteria. Frequent forums such as operating committee meetings should be held to discuss lessons learned and maximize successful coordination.

11. Short Term Load Forecasting

A. What Utilities Do Today

Daily load projections are continuously updated so that short-term resource plans can be developed with the most accurate load data possible.

B. Potential Impact of Competition

Individual generation providers will perform their own market analyses.

Short-term load forecasts will become an aggregation of numerous market participants' expected loads.

C. Recommendations

With an ISO: The ISO should be responsible for day-ahead coordination of load forecasts. Projected load requirements should be specified by scheduling entities (e.g., marketers, aggregators, and authorized customers.) For planning purposes, weekly and monthly projections should be provided by the ISO.

Without an ISO: The Control Area Operator (functionally separated from generation) should be responsible for day-ahead coordination of load forecasts and should provide the forecast to the Security Coordinator. Projected load requirements should be specified by scheduling entities (e.g., marketers, aggregators, and authorized customers). For planning purposes, weekly and monthly projections should be provided by the Security Coordinator.

D. Enforcement

With an ISO: Enforced by the ISO. Scheduling entities which fail to provide accurate day-ahead load forecasts will face economic risks as provided by FERC-approved tariffs, such as: 1) Lack of transmission access, and 2) Possible energy imbalance costs.

Without an ISO: Enforced by WSCC-designated Security Coordinator. Scheduling entities which fail to provide accurate day-ahead load forecasts will face economic risks as provided by FERC-approved tariffs, such as: 1) Lack of transmission access, and 2) Possible energy imbalance costs.

12. Operating Reserves

A. What Utilities Do Today

Utilities comply with criteria for operating reserves, which are based on a percentage of load and the largest generating unit on line (largest single hazard). At least one half of required reserves must be unloaded, on line generation (spinning reserves). All operating reserves must be fully available within 10 minutes.

B. Potential Impact of Competition

Retail competition may bring about changes in the assignment of responsibilities and mechanisms for compensation for this activity. (FERC Order 888 requires jurisdictional utilities' control areas to offer to provide operating reserves, spinning and supplemental, as ancillary services in wholesale transactions.)

C. Recommendations

With ISO: Each electric service provider providing firm capacity and energy to end-use customers should provide for the delivery of its proportionate share of the Operating

Reserves required by the Control Area Operator to meet its obligations under NERC/WSCC operating criteria. This may be accomplished by:

1) putting the machines providing Spinning Reserve under control of the Control Area's Automatic Generation Control (AGC) System;

2) purchasing Spinning Reserves from the Control Area Operator or from other owners of power plants within the Control Area that are operating under its AGC System; or

3) by making specific arrangements, including transmission service, on-line metering and telemetry control signals required to allow dynamic control of on-line machines outside the Control Area boundary. An operating agreement, between the Control Area Operator and the electric service provider's generation source, identifying the power plant(s), plant operator(s) and clear lines of communication regarding dispatch of the Contingency Reserve (non-spinning) portion of Operating Reserves may also be required.

When the electric service provider obtains this service from a third party, and problems arise where it is not being provided, the electric service provider should have procedures in place for the ISO to pick up its reserve obligations or it will be receiving imbalanced services.

Without an ISO: Each electric service provider providing firm capacity and energy to end-use customers should provide for the delivery of its proportionate share of the Operating Reserves required by the Control Area Operator to meet its obligations under NERC/WSCC operating criteria. This may be accomplished by:

1) putting the machines providing Spinning Reserve under control of the Control Area's Automatic Generation Control (AGC) System;

2) purchasing Spinning Reserves from the Control Area Operator or from other owners of power plants within the Control Area that are operating under its AGC System; or

3) by making specific arrangements, including transmission service, on-line metering and telemetry control signals required to allow dynamic control of on-line machines outside the Control Area boundary. An operating agreement, between the Control Area Operator and the electric service provider's generation source, identifying the power plant(s), plant operator(s) and clear lines of communication regarding dispatch of the Contingency Reserve (non-spinning) portion of Operating Reserves may also be required.

When the electric service provider obtains this service from a third party, and problems arise where it is not being provided, the electric service provider should have procedures in place for the Control Area Operator to pick up its reserve obligations or it will be receiving imbalanced services.

D. Enforcement

With ISO: The Control Area Operator (which may be the ISO), NERC/WSCC and ACC. (The ACC should require all entities offering to supply power to end-users in the state to provide Operating Reserves required under NERC/WSCC criteria as a condition of doing business in the state.)

Without ISO: The Control Area Operator, NERC/WSCC and ACC. (The ACC should require all entities offering to supply power to end-users in the state to provide Operating Reserves required under NERC/WSCC criteria as a condition of doing business in the state.)

13. Provide Regulating Capability

A. What Utilities Do Today

Each utility maintains sufficient regulating capability at all times to follow continuous changes in load. This is required to maintain system frequency.

B. Potential Impact of Competition

Retail competition may bring about changes in the assignment of responsibilities and mechanisms for compensation for this activity. (FERC Order 888 requires that regulation and frequency response be provided by jurisdictional utilities' control areas as an ancillary service in wholesale transactions. A purchaser of transmission services must purchase this service from the transmission provider, unless it can demonstrate that it can self provide or acquire the service from another provider.)

C. Recommendations

With ISO: The electric service provider should be responsible for having adequate regulating capability for its contracts; unless the customer chooses to self provide regulating capability, purchase this service from the Control Area (which may be an ISO), or purchase it from a qualified third party. When the service is self provided or obtained from a third party, transmission for regulating capacity must be obtained too. In addition, the electric service provider is responsible for getting the required communications, telemetering equipment and computer programming in place before it can receive this service from a third party.

The Control Area (which may be an ISO) should have real time knowledge of the load's regulation requirements and its provider. This includes status of units providing telemetering equipment at all locations and the transmission path used.

Any time regulation is provided outside the host Control Area, coordination is required between the two Control Areas.

When the electric service provider obtains this service from a third party, and problems arise where it is not being provided the service, the electric service provider should have procedures in place for this with the ISO or it will be receiving imbalanced services.

Without ISO: The electric service provider should be responsible for having adequate regulating capability for its contracts; unless the customer chooses to self provide regulating capability, purchase this service from the Control Area or purchase it from a qualified third party. When the service is self provided or obtained from a third party, transmission for regulating capacity must be obtained too. In addition, the electric service provider is responsible for getting the required communications, telemetering equipment and computer programming in place before it can receive this service from a third party.

The Control Area should have real time knowledge of the load's regulation requirements and its provider. This includes status of units providing telemetering equipment at all locations and the transmission path used.

Any time regulation is provided outside the host control area, coordination is required between the two Control Areas.

When the electric service provider obtains this service from a third party, and problems arise where it is not being provided, the electric service provider should have procedures in place for the host Control Area to pick up its regulating capacity or it will be receiving imbalanced services.

D. Enforcement

With ISO: Economic penalties for noncompliance with WSCC/NERC mandatory compliance criteria.

This could and should be part of the requirements of the electric service provider prior to obtaining transmission from the Control Area or ISO.

Without an ISO: Enforcement will occur through the Control Area using established WSCC guidelines.

This could and should be part of the requirements of the electric service provider prior to obtaining transmission from the Control Area.

14. Determine Short Term Resource Plan

A. What Utilities Do Today

Utilities develop short term resource plans to meet load and comply with all reserve and regulating criteria. Regional and local resource status and fuel availability are factored into plans.

B. Potential Impact of Competition

Becomes market driven.

Load responsibilities become contractual.

C. Recommendations

With an ISO: The ISO should be responsible for ensuring the provision of adequate reserves. Control Areas must have real-time control of delivery to customer loads that desire non-firm contracts.

Without an ISO: The Control Area should be responsible for ensuring the provision of adequate reserves. Control Areas must have real-time control of delivery to customer loads that desire non-firm contracts with the Control Area.

D. Enforcement

With an ISO: Enforcement will occur through economic incentive/penalties as provided by FERC-approved ISO agreements.

Without an ISO: Enforcement will occur through the Control Area using established WSCC agreements.

15. Generator Contingency Planning

A. What Utilities Do Today

Plans are developed in advance for loss of generators.

B. Potential Impact of Competition

Contingency planning becomes more complex due to the increased number of schedules and market participants.

C. Recommendations

With ISO: The ISO should be responsible for planning for generator contingencies such that all NERC and WSCC operating criteria are met. The ISO will determine reserve requirements and prepare plans for activation of reserves following specific contingencies. Contracts will have to be in place with generation providers and daily contingency plans should be coordinated with and communicated to these providers. The Control Area (which may be the ISO) should have real-time control of delivery to customer loads when non-firm delivery contracts are involved.

Without ISO: The Control Area Operator should remain responsible for planning for generator contingencies such that all NERC and WSCC operating criteria are met. The Control Area Operator will determine reserve requirements and prepare plans for activation of reserves following specific contingencies. Contracts will have to be in place with generation providers and daily contingency plans should be coordinated with and communicated to these providers. The Control Area should have real-time control of delivery to customer loads when non-firm delivery contracts are involved.

D. Enforcement

With ISO: The Control Area (which may be an ISO) will be subject to sanctions for not meeting NERC and WSCC operating criteria. Protocols should be developed so that capacity markets offer economic incentives to generation providers to meet resource reserve commitments when needed.

Without ISO: The Control Area will be subject to sanctions for not meeting NERC and WSCC operating criteria. Protocols should be developed so that capacity markets offer economic incentives to generation providers to meet resource reserve commitments when needed.

16. Annual and Seasonal Transmission Operating Studies

A. What Utilities Do Today

Arizona utilities coordinate with other utilities in the Desert Southwest to perform annual analysis on the transmission system. Anticipated operating conditions and system changes from the prior year are modeled and operating limits are developed. Individual utilities perform seasonal studies to determine potential operating problems or operating limits in specific areas for specific loading or system conditions such as planned equipment outages. All analyses are done for normal systems and all single equipment outage conditions. Simulation results must comply with equipment loading, voltage and system stability criteria to be acceptable.

B. Potential Impact of Competition

Since generation providers will be in competition for market share and the uses of the transmission system may be different, establishing accurate coordinated operating studies may be more difficult.

C. Recommendations

With an ISO: The ISO should be responsible for coordinating annual and seasonal transmission system analysis in order to mitigate the potential difficulties in establishing the accuracy of operating studies in a competitive environment. Mechanisms should be developed to accomplish coordination between generation providers and transmission facilities owners (and possibly other stakeholders).

Without an ISO: The Security Coordinator should be responsible for coordinating annual transmission system analysis in order to mitigate the potential difficulties in establishing the accuracy of operating studies in a competitive environment. Mechanisms should be developed to accomplish coordination between generation providers and transmission facilities owners (and possibly other stakeholders).

D. Enforcement

With an ISO: The Transmission Operator (which may be an ISO) will be subject to sanctions for not meeting NERC and WSCC operating criteria. (The WSCC operating criteria prohibits a transmission operator from operating under conditions that have not been studied.)

Without an ISO: The Control Area Operator will be subject to sanctions for not meeting NERC and WSCC operating criteria. (The WSCC operating criteria prohibits a transmission operator from operating under conditions that have not been studied.)

17. Forced Transmission Outage Operating Studies

A. What Utilities Do Today

When equipment forced out of service cannot be restored quickly, technical analyses are performed to determine the safe operating limits with that equipment out of service.

B. Potential Impact of Competition

Since generation providers will be in competition for market share and the uses of the transmission system may be different, establishing accurate coordinated operating studies may be more difficult.

C. Recommendations

With an ISO: The ISO should be responsible for coordinating forced transmission outage analysis in order to mitigate the potential difficulties in establishing the accuracy of outage studies in a competitive environment.

Without an ISO: The Security Coordinator should be responsible for coordinating forced transmission outage analysis in order to mitigate the potential difficulties in establishing the accuracy of outage studies in a competitive environment. Mechanisms should be developed to accomplish coordination between generation providers and transmission facilities owners (and possibly other stakeholders).

D. Enforcement

With an ISO: The Transmission Operator (which may be an ISO) will be subject to sanctions for not meeting NERC and WSCC operating criteria. (The WSCC operating criteria prohibits a transmission operator from operating under conditions that have not been studied.)

Without an ISO: The Control Area Operator will be subject to sanctions for not meeting NERC and WSCC operating criteria. (The WSCC operating criteria prohibits a transmission operator from operating under conditions that have not been studied.)

18. Planned Transmission Outage Operating Studies

A. What Utilities Do Today

When equipment is taken out of service on a planned basis, technical analyses are performed to determine safe operating limits with that equipment out of service.

B. Potential Impact of Competition

Since generation providers will be in competition for market share and the uses of the transmission system may be different, establishing accurate coordinated operating studies may be more difficult.

C. Recommendations

With an ISO: The ISO should be responsible for coordinating planned transmission outage analysis in order to mitigate the potential difficulties in establishing the accuracy of operating studies in a competitive environment.

Without an ISO: The Security Coordinator should be responsible for coordinating planned transmission outage analysis in order to mitigate the potential difficulties in establishing the accuracy of operating studies in a competitive environment. Mechanisms should be developed to accomplish coordination between generation providers and transmission facilities owners (and possibly other stakeholders).

D. Enforcement

With an ISO: The Transmission Operator (which may be an ISO) will be subject to sanctions for not meeting NERC and WSCC operating criteria. (The WSCC operating criteria prohibits a transmission operator from operating under conditions that have not been studied.)

Without an ISO: The Control Area Operator will be subject to sanctions for not meeting NERC and WSCC operating criteria. (The WSCC operating criteria prohibits a transmission operator from operating under conditions that have not been studied.)

19. Coordination of Transmission Equipment Construction/Maintenance

A. What Utilities Do Today

Utilities coordinate all construction and maintenance activities on the transmission system with all involved personnel within their organization and with all other affected utilities.

B. Potential Impact of Competition

Transmission outage schedules could be manipulated to enhance generation market power and to increase transmission congestion revenue.

Generation and transmission facilities owners will be driven by different economic incentives making coordination more challenging.

C. Recommendations

With an ISO: The ISO should be responsible for the coordination of transmission equipment outages in order to facilitate construction and maintenance activities with all affected transmission providers. This should be done in a manner which minimizes transmission congestion. The ISO should have final authority over planned outage schedules. All transmission providers should be responsible for fully cooperating with these coordination efforts.

Without an ISO: The Outage Coordinator should be responsible for the coordination of transmission equipment outages in order to facilitate construction and maintenance activities with all affected transmission providers. This should be done in a manner, which minimizes transmission congestion. An Outage Coordinator should have final authority over planned outage schedules. All transmission providers should be responsible for fully cooperating with these coordination efforts.

D. Enforcement

With an ISO: The ISO and all transmission providers will be subject to sanctions for not meeting NERC and WSCC operating criteria. There should be a contract between ISO and Transmission Facility Operators outlining authority, duties and responsibilities of each party. Abuse of market power may be brought to FERC.

Without an ISO: The Outage Coordinator and all transmission providers will be subject to sanctions for not meeting NERC and WSCC operating criteria. There should be a contract between the Outage Coordinator and Transmission Facility Operators outlining authority, duties and responsibilities of each party. Abuse of market power may be brought to FERC.

20. Unit Commitment for Reliability - Must Run Units

A. What Utilities Do Today

Generators are dispatched for security and reliability reasons, such as providing voltage support or unloading transmission equipment.

B. Potential Impact of Competition

Mechanisms for recovering cost of committing units for reliability purposes will change.

Increased potential for abuses of market power in local generation.

C. Recommendations

With ISO: The ISO should be responsible for obtaining the unit commitment needed for reliability. This may require units to be committed, which would not be committed based on economics. This will require agreements to be in place between the ISO and local generation providers. These purchases should be made using a least-cost approach. For example, to the extent that multiple units are available in addressing reliability, bidding can be used. When market power exists, the price should be regulated.

Without ISO: The transmission provider should be responsible for obtaining the unit commitment needed for reliability. This may require units to be committed, which would not be committed based on economics. This will require agreements to be in place between the transmission provider and local generation providers. These purchases should be made using a least-cost approach. For example, to the extent that multiple units are effective in addressing reliability, bidding can be used. When market power exists, the price should be regulated.

D. Enforcement

With ISO: The Control Area Operator (which could be the ISO) will be subject to sanctions for not meeting NERC and WSCC operating criteria. The price of power from "must run" units should be regulated by the ACC.

Without ISO: The transmission provider will be subject to sanctions for not meeting NERC and WSCC operating criteria. The price of power from "must run" units should be regulated by the ACC.

21. Load Frequency Control

A. What Utilities Do Today

Automatic Generation Control (AGC) programs in each utility's Energy Management System (EMS) continuously adjust generation output to match load and to maintain system frequency.

B. Potential Impact of Competition

Retail competition may bring about changes in the assignment of responsibilities and mechanisms for compensation for this activity. (FERC Order 888 requires that regulation and frequency response be provided by jurisdictional utilities' control areas as an ancillary service in wholesale transactions. A purchaser of transmission services must purchase this service from the transmission provider, unless it can demonstrate that it can acquire the service from another provider).

C. Recommendations

With ISO: This service occurs automatically as the result of two other services: spinning reserve and regulation services (see activities 12 & 13). Generation that is on line, with operational governors and unloaded automatically, responds to any frequency changes. Units providing regulation service are continuously responding to load changes within the ISO.

The customer or its agent should be responsible for obtaining these two services. If the requirements for spinning reserve and regulation services are met, then Load Frequency Control is covered.

Without ISO: This service occurs automatically as the result of two other services: spinning reserve and regulation services (see activities 12 & 13). Generation that is on line, with operational governors and unloaded automatically, responds to any frequency changes. Units providing regulation service are continuously responding to load changes within the control area.

The customer or its agent should be responsible for obtaining these two services. If the requirements for spinning reserve and regulation services are met, then Load Frequency Control is covered.

D. Enforcement

With ISO: Economic penalties for noncompliance with WSCC/NERC mandatory compliance criteria.

This could and should be part of the requirements of the electric service provider prior to obtaining transmission from the Control Area or the ISO.

Without an ISO: Enforcement will occur through the Control Area using established WSCC guidelines.

22. Generator Contingencies

A. What Utilities Do Today

When generator outages occur, spinning reserves are automatically activated and the operator activates other operating reserves or purchases energy to totally replace the lost generation within 10 minutes. The operator must also start up additional generation or purchase capacity to reestablish operating reserves within 60 minutes.

B. Potential Impact of Competition

Retail competition may bring about changes in the assignment of responsibilities and mechanisms for compensation for this activity.

C. Recommendations

With ISO: The ISO should be responsible for responding to generator contingencies such that all NERC and WSCC operating criteria are met. The ISO should activate reserves that have either been self-provided by load serving entities or have been obtained as ancillary services for the ISO to provide. The Control Area (which may be the ISO) should have real-time control of delivery to customer loads when non-firm delivery contracts are involved.

Without ISO: The Control Area Operator should remain responsible for responding to generator contingencies such that all NERC and WSCC operating criteria are met. The Control Area Operator should activate reserves that have either been self-provided by load serving entities or have been obtained as ancillary services for the Control Area Operator to provide. Control Areas should have real-time control of delivery to customer loads when non-firm delivery contracts are involved.

D. Enforcement

With ISO: The Control Area Operator (which may be the ISO) will be subject to sanctions for not meeting NERC and WSCC operating criteria. Generation providers should have economic incentives overseen by the ACC and the capacity market to meet resource reserve commitments when called on to activate.

Without ISO: The Control Area Operator will be subject to sanctions for not meeting NERC and WSCC operating criteria. Generation providers should have economic incentives overseen by the ACC and the capacity market to meet resource reserve commitments when called on to activate.

23. Transmission System Monitoring and Control

A. What Utilities Do Today

Operators continuously monitor and control all transmission system parameters such as loading, voltage, proximity to operating limits, status of equipment and remedial action schemes.

B. Potential Impact of Competition

The process under which system operators instruct generating units to change their operation based on reliability needs will change.

Potential conflicts of interest with generation and transmission curtailments may occur.

C. Recommendations

With an ISO: The ISO dispatchers should be responsible for continuous monitoring of the transmission system parameters such as loading, voltage, proximity to operating limits, status of equipment and remedial action schemes. The ISO should have protocols to address potential conflicts of interest.

Without an ISO: The Control Area Operator dispatchers should be responsible for continuous monitoring of the transmission system parameters such as loading, voltage, proximity to operating limits status of equipment and remedial action schemes. To address potential conflicts of interest with generation and transmission, functional separation would have to be closely monitored by regulatory authorities.

D. Enforcement

With an ISO: The Control Area Operator (which may be an ISO) will be subject to sanctions for not meeting NERC and WSCC operating criteria.

Without an ISO: The Control Area Operator will be subject to sanctions for not meeting NERC and WSCC operating criteria.

24. Voltage Control

A. What Utilities Do Today

Operators continuously control system voltage by changing generator unit Var output, taps on load-tap-changing transformers, and switching capacitors and reactors.

B. Potential Impact of Competition

Retail competition may bring about changes in the assignment of responsibilities and mechanisms for compensation for this activity. (FERC Order 888 requires jurisdictional utilities' control areas to provide reactive supply and voltage control from generation sources as an ancillary service for wholesale transactions. Transmission customers must purchase this service from the transmission provider unless an alternative approach is mutually agreed upon. Voltage control from transmission sources is considered by FERC to be an integral part of transmission service.)

C. Recommendations

With ISO: Due to its nature, this service can only be provided through the ISO by the transmission provider, the Utility Distribution Company, the customer's self generation or a local power producer. The ISO should have the authority to direct the operation of the reactive output of all generation used to support voltage in its area.

Sources of reactive power in the electric system are: a) generation and synchronous condensers, and b) transmission lines and reactive devices. Financial compensation for the generation is provided as an ancillary service in the Open Access Transmission Tariff. Compensation for the lines and reactive devices is included within the transmission and distribution service rates.

Customers with loads at a single point of delivery in excess of 1-10MW should be required to provide power factor correction so that other customers do not have to pay for the devices that support this load.

The Utility Distribution Company should provide voltage control devices for smaller customers. The goal is to meet IEEE and ANSI standards.

Without ISO: Due to its nature, this service can only be provided by the host control area, the transmission provider, the Utility Distribution Company, the customer's self generation or a local power producer. The Control Area should have the authority to direct the operation of the reactive output of all generation used to support voltage in its area.

Sources of reactive power in the electric system are: a) generation and synchronous condensers, and b) transmission lines and reactive devices. Financial compensation for the generation is provided as an ancillary service in the Open Access Transmission Tariff. Compensation for the lines and reactive devices is included within the transmission and distribution service rates.

Customers with loads at a single point of delivery in excess of 1-10 MW should be required to provide power factor correction so that other customers do not have to pay for the devices that support this load.

The Utility Distribution Company should provide voltage control devices for smaller customers. The goal is to meet IEEE and ANSI standards.

D. Enforcement

With ISO: This will be part of the FERC approved transmission and ACC approved distribution agreements that the electric service provider has with the transmission and Utility Distribution Companies.

Without ISO: This will be part of the FERC approved transmission and ACC approved distribution agreements that the electric service provider has with the transmission and Utility Distribution Companies.

25. Scheduling

A. What Utilities Do Today

Operators must map resource plans into the transmission system by scheduling all transactions on specific transmission lines and on control-area-to-control-area interconnections.

B. Potential Impact of Competition

Due to potential increases in the volume of transactions, the process of scheduling transactions will change.

C. Recommendations

With ISO: The ISO should be responsible for administering the scheduling of all deliveries from a defined point of receipt into the transmission system and to a defined point of delivery from the transmission system. Each entity providing capacity and energy to retail customers should be required to provide hourly schedules of expected deliveries on the prior business day.

A "scheduling coordinator" should provide aggregation of customers' schedules to the ISO. Due to the increased volume of transactions, the scheduling coordinator's functions should be defined and developed.

Without ISO: The Control Area Operator should be responsible for administering the scheduling of all deliveries from a defined point of receipt into the transmission system and to a defined point of delivery from the transmission system. Each entity providing capacity and energy to retail customers should be required to provide hourly schedules of expected deliveries on the prior business day.

A "scheduling coordinator" should provide aggregation of customers' schedules to the Control Area. Due to the increased volume of transactions the scheduling coordinator's functions should be defined and developed.

D. Enforcement

With ISO: The scheduling protocols will be included in the transmission agreement that the electric service provider has with the transmission providers.

Without ISO: The scheduling protocols will be included in the transmission agreement that the electric service provider has with the transmission providers.

26. Alarm Response and Control, and Curtailments

A. What Utilities Do Today

Operators respond to alarms for system parameters outside limits and equipment problems such as equipment temperatures or pressures outside of their normal ranges. When changes in system conditions result in new operating limits which are lower than existing schedules or flows; the operator initiates schedule curtailments in order to reduce schedules and/or flows until they are within the new reduced operating limits.

B. Potential Impact of Competition

Curtailing schedules will be more complex due to the increase in the volume of schedules and the increase in the number of scheduling entities.

Potential conflicts of interest with generation and transmission curtailments may occur.

C. Recommendations

With an ISO: The ISO should be responsible for the development of protocols for appropriate response to alarms for system parameters outside limits and equipment problems such as equipment temperatures or pressures outside their normal operating range.

The ISO operator should be responsible for initiating schedule curtailments and ensuring that schedules are in fact curtailed. All entities involved in scheduling should be responsible for following all applicable NERC and WSCC scheduling criteria and procedures to facilitate schedule curtailment.

Nondiscriminatory curtailment protocols should be developed.

Without an ISO: The Control Area Operator dispatchers should continue to be responsible for the appropriate response to alarms for system parameters outside limits and equipment problems such as equipment temperatures or pressures outside their normal operating range. To address potential conflicts of interest with generation and transmission, functional separation would have to be closely monitored by regulatory authorities.

The Control Area Operator should be responsible for initiating schedule curtailments and ensuring that schedules are in fact curtailed. All entities involved in scheduling should continue to be responsible for following all applicable NERC and WSCC scheduling criteria and procedures to facilitate schedule curtailment.

Nondiscriminatory curtailment protocols should be developed.

D. Enforcement

With an ISO: The Control Area Operator (which may be an ISO) will be subject to sanctions for not meeting NERC and WSCC operating criteria concerning alarm response.

All entities involved in scheduled curtailments will be subject to sanctions for not meeting NERC and WSCC scheduling criteria.

Without an ISO: The Control Area Operator will be subject to sanctions for not meeting NERC and WSCC operating criteria.

All entities involved in scheduled curtailments will be subject to sanctions for not meeting NERC and WSCC scheduling criteria.

27. Disturbance Response

A. What Utilities Do Today

When disturbances occur on the electric power system, the operator quickly assesses the cause and extent of the disturbance, takes action to mitigate the effect of the disturbance, and prepares the system for possible additional outages.

B. Potential Impact of Competition

Restoration of service may involve new protocols.

Potential conflicts of interest with generation and transmission curtailments may occur.

C. Recommendations

With an ISO: The ISO dispatchers should be responsible for quickly assessing the cause and extent of disturbances and then taking action to mitigate the effect of the disturbance and preparing the system for possible additional outages.

Without an ISO: The Control Area Operator dispatchers should be responsible for quickly assessing the cause and extent of disturbances and then taking action to mitigate the effect of the disturbance and preparing the system for possible additional outages. To address potential conflicts of interest with generation and transmission, functional separation would have to be closely monitored by regulatory authorities.

D. Enforcement

With an ISO: The ISO will be subject to sanctions for not meeting NERC and WSCC operating criteria. This will include, but is not limited to, increasing the minimum contingency reserve.

Without an ISO: The Control Area Operator will be subject to sanctions for not meeting NERC and WSCC operating criteria. This will include, but is not limited to, increasing the minimum contingency reserve.

28. Coordinate Field Work

A. What Utilities Do Today

The operator must accurately process clearances to assure equipment is deenergized and will remain deenergized to allow safe work on equipment in the field. Hold Tags are issued when work is performed on energized equipment to assure that equipment will not be reenergized if the work performed causes an inadvertent outage to that equipment.

B. Potential Impact of Competition

No change

C. Recommendations

With an ISO: The ISO should have authority over all planned transmission system outages. The transmission facilities owners' facility operators will be responsible for accurately processing clearances to assure equipment is deenergized to allow safe work on equipment in the field. The Transmission Facilities Providers are subject to the ISO's maintenance protocols.

Without an ISO: The Control Area Operator should have authority over all planned transmission system outages. The transmission facilities owners' facility operators will be responsible for accurately processing clearances to assure equipment is deenergized to allow safe work on equipment in the field.

D. Enforcement

With an ISO: The ISO will be subject to sanctions for not meeting NERC and WSCC operating criteria. The Transmission Facilities Providers are subject to the ISO's maintenance protocols.

Without an ISO: The Transmission Facilities Providers will be subject to sanctions for not meeting NERC and WSCC operating criteria.

29. Coordinate and Communicate with Other Control Centers

A. What Utilities Do Today

Continuous coordination and communication between all control centers in all aspects of operations is essential for reliability.

B. Potential Impact of Competition

Potential conflicts of interest may lessen the incentive to coordinate and communicate between generators and Transmission Facilities Providers.

The number of transactions will increase, thereby complicating communications.

C. Recommendations

With an ISO: The Control Area Operator (which may be an ISO) should be responsible for the continuous coordination and communication between all control centers and Security Coordinators.

Without an ISO: The Control Area Operator should be responsible for the continuous coordination and communication between all control centers and Security Coordinators. To address potential conflicts of interest with generation and transmission, functional separation would have to be closely monitored by regulatory authorities.

D. Enforcement

With an ISO: The Control Area Operator (which may be an ISO) will be subject to sanctions for not meeting NERC and WSCC operating criteria.

Without an ISO: The Control Area will be subject to sanctions for not meeting NERC and WSCC operating criteria.

30. Metering

A. What Utilities Do Today

Most customers have meters that are not dynamically linked to the control of generation.

B. Potential Impact of Competition

May require more sophisticated metering, such as:
The general Levels of Metering/Control Sophistication:

Level 1	kWh (energy only) metering
Level 2	Hourly interval data recording
Level 3	Reactive metering (including above)
Level 4	All of the above PLUS Dial-up communication
Level 5	Real-time communication/control (RTU or RTU-like meter)
Level 6	Real-time PLUS Load Break Equipment

C. Recommendations

With ISO: Metering standards should be developed which promote the objectives of retail access. The metering requirements for a given customer should be commensurate with the flexibility being requested by that customer (e.g., preferring to be interrupted rather than purchase operating reserve services). Load profiling should be used for low-usage customers (e.g., residential), although it may be necessary to limit the flexibility for such customers in the purchase of ancillary services.

Without ISO: Metering standards should be developed which promote the objectives of retail access. The metering requirements for a given customer should be commensurate with the flexibility being requested by that customer (e.g., preferring to be interrupted rather than purchase operating reserve services). Load profiling should be used for low-usage customers (e.g., residential), although it may be necessary to limit the flexibility for such customers in the purchase of ancillary services.

D. Enforcement

With ISO: Adherence to approved metering standards will be a condition of service.

Without ISO: Adherence to approved metering standards will be a condition of service.

31. Energy Imbalance

A. What Utilities Do Today

Energy Imbalance is the algebraic difference between the actual energy received or delivered and the agreed-upon amount (scheduled) over an hour. Control Areas settle energy imbalances at the Control Area level and between Control Areas. This does not exist at the retail customer level.

B. Potential Impact of Competition

Energy imbalance service will be necessary at the scheduling entity level. The addition of numerous scheduling entities may cause the provision of energy imbalance service to be more complex.

C. Recommendations

With an ISO: The ISO should provide energy balancing service as an ancillary service under FERC Orders 888 and 888a. The protocol for billing the appropriate parties for this service should be established in conjunction with the development of the ISO's scheduling protocol.

Retail generation service tariffs filed by electric service providers with the ACC should clearly indicate whether energy imbalance service is included in the contract price charged to the retail access customer or is in addition to that contract price.

Without an ISO: The transmission provider should provide energy balancing service as an ancillary service under FERC Orders 888 and 888a. The transmission providers' FERC tariffs should provide ceiling prices for this service. The protocol for billing the appropriate parties for this service should be established in conjunction with the development of Arizona's retail access scheduling protocol.

Retail generation service tariffs filed by electric service providers with the ACC should clearly indicate whether energy imbalance service is included in the contract price charged to the retail access customer or is in addition to that contract price.

D. Enforcement

With an ISO: Economic incentive overseen by FERC and/or the ACC.

Without an ISO: Economic incentive overseen by FERC and/or the ACC.

APPENDIX A: Glossary of Terms

Taken from NERC Glossary of terms.

Ancillary Services — Interconnected Operations Services identified by the U.S. Federal Energy Regulatory Commission (Order No. 888 issued April 24, 1996) as necessary to effect a transfer of electricity between purchasing and selling entities and which a transmission provider must include in an open access transmission tariff. See also Interconnected Operations Services.

Energy Imbalance Service — Provides energy correction for any hourly mismatch between a transmission customer's energy supply and the demand served.

Operating Reserve: Spinning Reserve Service — Provides additional capacity from electricity generators that are on-line, loaded to less than their maximum output, and available to serve customer demand immediately should a contingency occur.

Operating Reserve: Supplemental Reserve Service — Provides additional capacity from electricity generators that can be used to respond to a contingency within a short period, usually ten minutes.

Reactive Supply and Voltage Control From Generating Sources Service — Provides reactive supply through changes to generator reactive output to maintain transmission line voltage and facilitate electricity transfers.

Regulation and Frequency Response Service — Provides for following the moment-to-moment variations in the demand or supply in a Control Area and maintaining scheduled Interconnection frequency.

Scheduling, System Control, and Dispatch Service — Provides for a) scheduling, b) confirming and implementing an interchange schedule with other Control Areas, including intermediary Control Areas providing transmission service, and c) ensuring operational security during the interchange transaction.

Area Control Error — The instantaneous difference between actual and scheduled interchange, taking into account the effects of frequency bias.

Automatic Generation Control (AGC) — Equipment that automatically adjusts a Control Area's generation to maintain its interchange schedule plus its share of frequency regulation.

The following AGC modes are typically available:

a. Tie Line Bias Control — Automatic generation control with both frequency and interchange terms of Area Control Error considered.

b. Constant Frequency (Flat Frequency) Control — Automatic generation control with the interchange term of Area Control Error ignored. This Automatic Generation Control mode attempts to maintain the desired frequency without regard to interchange.

c. Constant Net Interchange (Flat Tie Line) Control — Automatic generation control with the frequency term of Area Control Error ignored. This Automatic Generation Control mode attempts to maintain interchange at the desired level without regard to frequency.

Available Transfer Capability (ATC) — A measure of the transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses. ATC is defined as the Total Transfer Capability (TTC), less the Transmission Reliability Margin (TRM), less the sum of existing transmission commitments (which includes retail customer service) and the Capacity Benefit Margin (CBM).

Nonrecallable Available Transfer Capability (NATC) — Total Transmission Capability less the Transmission Reliability Margin, less nonrecallable reserved transmission service (including the Capacity Benefit Margin).

Recallable Available Transmission Capability (RATC) — Total Transmission Capability less the Transmission Reliability Margin, less recallable transmission service, less non-recallable transmission service (including the Capacity Benefit Margin). RATC must be considered differently in the planning and operating horizons. In the planning horizon, the only data available are recallable and nonrecallable transmission service reservations, whereas in the operating horizon transmission schedules are known.

Baseload — The minimum amount of electric power delivered or required over a given period at a constant rate.

Blackstart Capability — The ability of a generating unit or station to go from a shutdown condition to an operating condition and start delivering power without assistance from the electric system.

Bulk Electric System — A term commonly applied to the portion of an electric utility system that encompasses the electrical generation resources and bulk transmission system.

Capacity — The rated continuous load-carrying ability, expressed in megawatts (MW) or megavolt-amperes (MVA) of generation, transmission, or other electrical equipment.

Baseload Capacity — Capacity used to serve an essentially constant level of customer demand. Baseload generating units typically operate whenever they are available, and they generally have a capacity factor that is above 60%.

Peaking Capacity — Capacity used to serve peak demand. Peaking generating units operate a limited number of hours per year, and their capacity factor is normally less than 20%.

Net Capacity — The maximum capacity (or effective rating), modified for ambient limitations, that a generating unit, power plant, or electric system can sustain over a specified period, less the capacity used to supply the demand of station service or auxiliary needs.

Intermediate Capacity — Capacity intended to operate fewer hours per year than Baseload capacity but more than peaking capacity. Typically, such generating units have a capacity factor of 20% to 60%.

Firm Capacity — Capacity that is as firm as the seller's native load unless modified by contract. Associated energy may or may not be taken at option of purchaser. Supporting reserve is carried by the seller.

Capacity Benefit Margin (CBM) — That amount of transmission transfer capability reserved by load serving entities to ensure access to generation from interconnected systems to meet generation reliability requirements. Reservation of CBM by a load serving entity allows that entity to reduce its installed generating capacity below that which may otherwise have been necessary without interconnections to meet its generation reliability requirements. See Available Transfer Capability.

Capacity Emergency — A state when a system's or pool's operating capacity plus firm purchases from other systems, to the extent available or limited by transfer capability, is inadequate to meet the total of its demand, firm sales, and regulating requirements. See Energy Emergency.

Capacity Factor — The ratio of the total energy generated by a generating unit for a specified period to the maximum possible energy it could have generated if operated at the maximum capacity rating for the same specified period, expressed as a percent.

Cascading — The uncontrolled successive loss of system elements triggered by an incident at any location. Cascading results in widespread service interruption, which cannot be restrained from sequentially spreading beyond an area predetermined by appropriate studies.

Contingency — The unexpected failure or outage of a system component, such as a generator, transmission line, circuit breaker, switch, or other electrical element. A contingency also may include multiple components, which are related by situations leading to simultaneous component outages.

Control Area — An electric system or systems, bounded by interconnection metering and telemetry, capable of controlling generation to maintain its interchange schedule with other Control Areas and contributing to frequency regulation of the Interconnection.

Curtailability — The right of a transmission provider to interrupt all or part of a transmission service due to constraints that reduce the capability of the transmission network to provide that transmission service. Transmission service is to be curtailed only in cases where system reliability is threatened or emergency conditions exist.

Curtailment — A reduction in the scheduled capacity or energy delivery.

Demand — The rate at which electric energy is delivered to or by a system or part of a system, generally expressed in kilowatts or megawatts, at a given instant or averaged over any designated interval of time. Demand should not be confused with Load. Types of Demand include:

Instantaneous Demand — The rate of energy delivered at a given instant.

Average Demand — The electric energy delivered over any interval of time as determined by dividing the total energy by the units of time in the interval.

Integrated Demand — The average of the instantaneous demands over the demand interval.

Demand Interval — The time period during which electric energy is measured, usually in 15-, 30-, or 60-minute increments.

Peak Demand — The highest electric requirement occurring in a given period (e.g., an hour, a day, month, season, or year). For an electric system, it is equal to the sum of the metered net outputs of all generators within a system and the metered line flows into the system, less the metered line flows out of the system.

Coincident Demand — The sum of two or more demands that occur in the same demand interval.

Noncoincident Demand — The sum of two or more demands that occur in different demand intervals.

Contract Demand — The amount of capacity that a supplier agrees to make available for delivery to a particular entity and which the entity agrees to purchase.

Firm Demand — That portion of the Contract Demand that a power supplier is obligated to provide except when system reliability is threatened or during emergency conditions.

Billing Demand — The demand upon which customer billing is based as specified in a rate schedule or contract. It may be based on the contract year, a contract minimum, or a previous maximum and, therefore, does not necessarily coincide with the actual measured demand of the billing period.

Demand-Side Management — The term for all activities or programs undertaken by an electric system or its customers to influence the amount or timing of electricity use.

Indirect Demand-Side Management — Programs such as conservation, improvements in efficiency of electrical energy use, rate incentives, rebates, and other similar activities to influence electricity use.

Direct Control Load Management — The customer demand that can be interrupted by direct control of the system operator controlling the electric supply to individual appliances or equipment on customer premises. This type of control, when used by utilities, usually involves residential customers. Direct Control Load Management as defined here does not include Interruptible Demand.

Interruptible Demand — The magnitude of customer demand that, in accordance with contractual arrangements, can be interrupted by direct control of the system operator or by action of the customer at the direct request of the system operator. In some instances, the demand reduction may be initiated by the direct action of the system operator (remote tripping) with or without notice to the customer in accordance with contractual provisions. Interruptible Demand as defined here does not include Direct Control Load Management.

Derating (Generator) — A reduction in a generating unit's Net Dependable Capacity.

Forced Derating — An unplanned component failure (immediate, delayed, postponed) or other condition that requires the output of the unit be reduced immediately or before the next weekend.

Maintenance Derating — The removal of a component for scheduled repairs that can be deferred beyond the end of the next weekend, but requires a reduction of capacity before the next planned outage.

Planned Derating — The removal of a component for repairs that is scheduled well in advance and has a predetermined duration.

Scheduled Derating — A combination of maintenance and planned deratings.

Dispatchable Generation — Generation available physically or contractually to respond to changes in system demand or to respond to transmission security constraints. See Must- Run Generation.

Disturbance — An unplanned event that produces an abnormal system condition.

Dynamic Rating — The process that allows a system element rating to vary with the changing environmental conditions in which the element is located.

Dynamic Schedule — A telemetered reading or value that is updated in real time and used as a schedule in the Automatic Generation Control/Area Control Error equation and the integrated value of which is treated as a schedule. Commonly used for "scheduling" commonly owned generation or remote load to or from another Control Area.

Economic Dispatch — The allocation of demand to individual generating units on line to effect the most economical production of electricity.

Electrical Energy — The generation or use of electric power by a device over a period of time, expressed in kilowatt hours (kWh), megawatt hours (MWh), or gigawatt hours (GWh).

Firm Energy — Electrical Energy backed by capacity, interruptible only on conditions as agreed upon by contract, system reliability constraints, or emergency conditions and where the supporting reserve is supplied by the seller.

Nonfirm Energy — Electrical Energy that may be interrupted by either the provider or the receiver of the energy by giving advance notice to the other party to the transaction. This advance notice period is equal to or greater than the minimum period agreed to in the contract. Nonfirm Energy may also be interrupted to maintain system reliability of third- party Transmission Providers. Nonfirm Energy must be backed up by reserves.

Emergency Energy — Electrical Energy purchased by a member system whenever an event on that system causes insufficient Operating Capability to cover its own demand requirement.

Economy Energy — Electrical Energy produced and supplied from a more economical source in one system and substituted for that being produced or capable of being produced by a less economical source in another system.

Off-Peak Energy — Electrical Energy supplied during a period of relatively low system demands as specified by the supplier.

On-Peak Energy — Electrical Energy supplied during a period of relatively high system demands as specified by the supplier

.**Element** — Any electric device with terminals that may be connected to other electric devices, such as a generator, transformer, circuit, circuit breaker, or bus section. See Rating, System Element Rating.

Limiting Element — The element that is either operating at its appropriate rating or would be following the limiting contingency and, as a result, establishes a system limit.

Emergency — Any abnormal system condition that requires automatic or immediate manual action to prevent or limit loss of transmission facilities or generation supply that could adversely affect the reliability of the electric system.

Energy Imbalance Service — See Ancillary Services.

Expected Unserved Energy — The expected amount of energy curtailment per year due to demand exceeding available capacity. It is usually expressed in megawatt hours (MWh).

Forecast — Predicted demand for electric power. A forecast may be short term (e.g., 15 minutes) for system operation purposes, long-term (e.g., five to 20 years) for generation planning purposes, or for any range in between. A forecast may include peak demand, energy, reactive power, or demand profile. A forecast may be made for total system demand, transmission loading, substation/feeder loading, individual customer demand, or appliance demand.

Forecast Uncertainty — Probable deviations from the expected values of factors considered in a forecast.

Frequency

Frequency Bias — A value, usually given in megawatts per 0.1 Hertz (MW/0.1 Hz), associated with a Control Area that relates the difference between scheduled and actual frequency to the amount of generation required to correct the difference.

Frequency Deviation — A departure from scheduled frequency.

Frequency Error — The difference between actual system frequency and the scheduled system frequency.

Frequency Regulation — The ability of a Control Area to assist the interconnected system in maintaining scheduled frequency. This assistance can include both turbine governor response and automatic generation control.

Frequency Response (Equipment) — The ability of a system or elements of the system to react or respond to a change in system frequency. Frequency Response (System) — The sum of the change in demand, plus the change in generation, divided by the change in frequency, expressed in megawatts per 0.1 Hertz (MW/0.1 Hz).

Scheduled Frequency — 60.0 Hertz, except during a time correction.

Host Control Area (HCA) — 1. A Control Area that confirms and implements scheduled Interchange for a Transmission Customer that operates generation or serves customers directly within the Control Area's metered boundaries. 2. The Control Area within whose metered boundaries a commonly owned unit or terminal is physically located.

Imbalance — A condition where the generation and interchange schedules do not match demand.

Inadvertent Energy Balancing — A Control Area's accounting of its inadvertent interchange, which is the accumulated difference between actual and scheduled interchange.

Inadvertent Interchange or Inadvertent — The difference between a Control Area's net actual interchange and net scheduled interchange.

Independent Power Producers (IPP) — As used in NERC reference documents and reports, any entity that owns or operates an electricity generating facility that is not included in an electric utility's rate base. This term includes, but is not limited to, cogenerators and small power producers and all other nonutility electricity producers, such as exempt wholesale generators who sell electricity.

Interchange — Electric power or energy that flows from one entity to another.

Actual Interchange — Metered electric power that flows from one entity to another.

Interchange Scheduling — The actions taken by scheduling entities to arrange transfer of electric power. The schedule consists of an agreement on the amount, start and end times, ramp rate, and degree of firmness.

Scheduled Interchange — Electric power scheduled to flow between entities, usually the net of all sales, purchases, and wheeling transactions between those areas at a given time.

Interconnected Operations Services (IOS) — Services that transmission providers may offer voluntarily to a transmission customer under Federal Energy Regulatory Commission Order No. 888 in addition to Ancillary Services. See also Ancillary Services.

Backup Supply Service — Provides capacity and energy to a transmission customer, as needed, to replace the loss of its generation sources and to cover that portion of demand that exceeds the generation supply for more than a short time.

Dynamic Scheduling Service — Provides the metering, telemetering, computer software, hardware, communications, engineering, and administration required to *electronically* move a transmission customer's generation or demand out of the Control Area to which it is physically connected and into a different Control Area.

Real Power Loss Service — Compensates for losses incurred by the Host Control Area(s) as a result of the interchange transaction for a transmission customer. Federal Energy Regulatory Commission's Order No. 888 requires that the transmission customer's service agreement with the Transmission Provider identify the entity responsible for supplying real power loss.

Restoration Service — Provides an offsite source of power to enable a Host Control Area to restore its system and a transmission customer to start its generating units or restore service to its customers if local power is not available.

Interconnected System — A system consisting of two or more individual electric systems that normally operate in synchronism and have connecting tie lines.

Intermediary Control Area — A Control Area that has connecting facilities in the scheduling path between the sending and receiving Control Areas and has operating agreements that establish the conditions for the use of such facilities.

Intra-Control Area Transaction — A transaction from one or more generating sources to one or more delivery points where all the sources and delivery points are entirely within the metered boundaries of the same Control Area.

Island — A portion of a power system or several power systems that is electrically separated from the interconnection due to the disconnection of transmission system elements.

Load Factor — A measure of the degree of uniformity of demand over a period of time, usually one year, equivalent to the ratio of average demand to peak demand expressed as a percentage. It is calculated by dividing the total energy provided by a system during the period by the product of the peak demand during the period and the number of hours in the period.

Load Following — An electric system's process of regulating its generation to follow the changes in its customers' demand.

Load Shedding — The process of deliberately removing (either manually or automatically) preselected customer demand from a power system in response to an abnormal condition to maintain the integrity of the system and minimize overall customer outages.

Loss of Load Expectation (LOLE) — The expected number of days in the year when the daily peak demand exceeds the available generating capacity. It is obtained by calculating the probability of daily peak demand exceeding the available capacity for each day and adding these probabilities for all the days in the year. The index is referred to as Hourly Loss-of-Load-Expectation if hourly demands are used in the calculations instead of daily peak demands. LOLE also is commonly referred to as Loss-of-Load-Probability. See Expected Unserved Energy.

Margin — The difference between net capacity resources and net internal demand. Margin is usually expressed in megawatts (MW).

Adequate Regulating Margin — The minimum on-line capacity that can be increased or decreased to allow the electric system to respond to all reasonable instantaneous demand changes to be in compliance with the Control Performance Criteria.

Available Margin — The difference between Available Resources and Net Internal Demand, expressed as a percent of Available Resources. This is the capacity available to cover random factors such as forced outages of generating equipment, demand forecast errors, weather extremes, and capacity service schedule slippages.

Capacity Margin — The difference between net capacity resources and net internal demand expressed as a percent of net capacity resources.

Metering — The methods of applying devices that measure and register the amount and direction of electrical quantities with respect to time.

Must-Run Generation — Generation designated to operate at a specific level and not available for dispatch. See Dispatchable Generation.

OASIS (Open -Access Same-Time Information System) — An electronic posting system for transmission access data that allows all Transmission Customers to view the data simultaneously.

Operating Criteria — The fundamental principles of reliable interconnected systems operation.

Operating Policies — The doctrine developed for interconnected systems operation. This doctrine consists of Criteria, Standards, Requirements, Guides, and instructions and apply to all Control Areas.

Operating Procedures — A set of policies, practices, or system adjustments that may be automatically or manually implemented by the system operator within a specified time frame to maintain the operational integrity of the interconnected electric systems.

Automatic Operating Systems — Special protection systems, remedial action schemes, or other operating systems installed on the electric systems that require *no intervention* on the part of system operators.

Normal (Precontingency) Operating Procedures — Operating procedures that are normally invoked by the system operator to alleviate potential facility overloads or other potential system problems in anticipation of a contingency.

Postcontingency Operating Procedures — Operating procedures that may be invoked by the system operator to mitigate or alleviate system problems after a contingency has occurred.

Operating Reserve: Spinning Reserve Service — See Ancillary Services.

Operating Reserve: Supplemental Reserve Service — See Ancillary Services.

Operating Standards — The obligations of a Control Area and systems functioning as part of a Control Area that are measurable. A Standard may specify monitoring and surveys for compliance.

Operating Transmission Limit — The maximum value of the most critical system operating parameter(s) which meets: (a) precontingency criteria as determined by equipment loading capability and acceptable voltage conditions, (b) transient performance criteria or, (c) postcontingency loading and voltage criteria.

Overlap Regulation Service — A method of providing regulation service in which the Control Area providing the regulation service incorporates some or all of another Control Area's tie lines and schedules into its own Automatic Generation Control/Area Control Error equation.

Parallel Path Flows — The difference between the scheduled and actual power flow, assuming zero inadvertent interchange, on a given transmission path. Synonyms: Loop Flows, Unscheduled Power Flows, and Circulating Power Flows.

Planning (System) — The process by which the performance of the electric system is evaluated and future changes and additions to the bulk electric systems are determined.

Planning Procedures — An explanation of how the Planning Policies are addressed and implemented by the NERC Engineering Committee, its subgroups, and the Regional Councils to achieve bulk electric system reliability.

Rating — The operational limits of an electric system, facility, or element under a set of specified conditions.

Continuous Rating — The rating as defined by the equipment owner that specifies the level of electrical loading, usually expressed in megawatts (MW) or other appropriate units that a system, facility, or element can support or withstand indefinitely without loss of equipment life.

Normal Rating — The rating as defined by the equipment owner that specifies the level of electrical loading, usually expressed in megawatts (MW) or other appropriate units that a system, facility, or element can support or withstand through the daily demand cycles without loss of equipment life.

Emergency Rating — The rating as defined by the equipment owner that specifies the level of electrical loading, usually expressed in megawatts (MW) or other appropriate units, that a system, facility, or element can support or withstand for a finite period. The rating assumes acceptable loss of equipment life or other physical or safety limitations for the equipment involved.

Reactive Supply and Voltage Control From Generating Sources Service — See Ancillary Services.

Real-Time Operations — The instantaneous operations of a power system as opposed to those operations that are simulated.

Region — One of the NERC Regional Reliability Councils or Affiliate.

Regional Reliability Council — One of nine Electric Reliability Councils that form the North American Electric Reliability Council (NERC).

Regional Transmission Group (RTG) — Voluntary organization of transmission owners, transmission users, and other entities interested in coordinating transmission planning and expansion and use on a regional and interregional basis.

Regulation and Frequency Response Service — See Ancillary Services.

Reliability — The degree of performance of the elements of the bulk electric system that results in electricity being delivered to customers within accepted standards and in the amount desired. Reliability may be measured by the frequency, duration, and magnitude of adverse effects on the electric supply. Electric system reliability can be addressed by considering two basic and functional aspects of the electric system — Adequacy and Security.

Adequacy — The ability of the electric system to supply the aggregate electrical demand and energy requirements of the customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements.

Security — The ability of the electric system to withstand sudden disturbances such as electric short circuits or unanticipated loss of system elements.

Reliability Criteria — Principles used to design, plan, operate, and assess the actual or projected reliability of an electric system.

Remedial Action Scheme — See Operating Procedures

Reserve

Operating Reserve — That capability above firm system demand required to provide for regulation, load forecasting error, equipment forced and scheduled outages, and local area protection.

Spinning Reserve — Unloaded generation, which is synchronized and ready to serve additional demand. It consists of Regulating Reserve and Contingency Reserve.

Regulating Reserve — An amount of spinning reserve responsive to Automatic Generation Control, which is sufficient to provide normal regulating margin.

Contingency Reserve — An additional amount of operating reserve sufficient to reduce Area Control Error to zero in ten minutes following loss of generating capacity, which would result from the most severe single contingency. At least 50% of this operating reserve shall be Spinning Reserve, which will automatically respond to frequency deviation.

Nonspinning Reserve — That operating reserve not connected to the system but capable of serving demand within a specific time, or Interruptible Demand that can be removed from the system in a specified time. Interruptible Demand may be included in the Nonspinning Reserve provided that it can be removed from service within ten minutes.

Planning Reserve — The difference between a Control Area's expected annual peak capability and its expected annual peak demand expressed as a percentage of the annual peak demand.

Response Rate

Emergency Response Rate — The rate of load change that a generating unit can achieve under emergency conditions, such as loss of a unit, expressed in megawatts per minute (MW/Min).

Normal Response Rate — The rate of load change that a generating unit can achieve for normal loading purposes expressed in megawatts per minute (MW/Min).

Schedule — An agreed-upon transaction size (megawatts), start and end time, beginning and ending ramp times and rate, and type required for delivery and receipt of power and energy between the contracting parties and the Control Area(s) involved in the transaction.

Security — See Reliability.

Single Contingency — The sudden, unexpected failure or outage of a system facility(s) or element(s) (generating unit, transmission line, transformer, etc.). Elements removed from service as part of the operation of a remedial action scheme are considered part of a single contingency.

Stability — The ability of an electric system to maintain a state of equilibrium during normal and abnormal system conditions or disturbances.

Small-Signal Stability — The ability of the electric system to withstand small changes or disturbances without the loss of synchronism among the synchronous machines in the system.

Transient Stability — The ability of an electric system to maintain synchronism between its parts when subjected to a disturbance of specified severity and to regain a state of equilibrium following that disturbance.

Substation — A facility for switching electrical elements, transforming voltage, regulating power, or metering.

Supervisory Control — A form of remote control comprising an arrangement for the selective control of remotely located facilities by an electrical means over one or more communications media.

Supervisory Control and Data Acquisition (SCADA) — A system of remote control and telemetry used to monitor and control the electric system.

System Operator — An individual at an electric system control center whose responsibility it is to monitor and control that electric system in real time.

Telemetering — The process by which measurable electrical quantities from substations and generating stations are instantaneously transmitted using telecommunication techniques.

Thermal Rating — The maximum amount of electrical current that a transmission line or electrical facility can conduct over a specified time period before it sustains permanent damage by overheating or before it violates public safety requirements.

Tie Line — A circuit connecting two or more Control Areas or systems of an electric system.

Tie Line Bias — A mode of operation under automatic generation control in which the area control error is determined by the actual net interchange minus the biased scheduled net interchange.

Time Error — An accumulated time difference between Control Area system time and the time standard. Time error is caused by a deviation in Interconnection frequency from 60.0 Hertz.

Time Error Correction — An offset to the Interconnection's scheduled frequency to correct for the time error accumulated on electric clocks.

Total Transfer Capability (TTC) — The amount of electric power that can be transferred over the interconnected transmission network in a *reliable* manner based on *all* of the following conditions:

1. For the existing or planned system configuration, and with normal (precontingency) operating procedures in effect, all facility loadings are within normal ratings and all voltages are within normal limits.

2. The electric systems are capable of absorbing the dynamic power swings, and remaining stable, following a disturbance that results in the loss of any single electric system element, such as a transmission line, transformer, or generating unit.

3. After the dynamic power swings subside following a disturbance that results in the loss of any single electric system element as described in 2 above, and after the operation of any automatic operating systems, but before any postcontingency operator-initiated system adjustments are implemented, all transmission facility loadings are within emergency ratings and all voltages are within emergency limits.

4. With reference to condition 1 above, in the case where precontingency facility loadings reach normal thermal ratings at a transfer level below that at which any first contingency transfer limits are reached, the transfer capability is defined as that transfer level at which such normal ratings are reached.
5. In some cases, individual system, power pool, subregional, or Regional planning criteria or guides may require consideration of specified multiple contingencies, such as the outage of transmission circuits using common towers or rights-of-way, in the determination of transfer capability limits. If the resulting transfer limits for these multiple contingencies are more restrictive than the single contingency considerations described above, the more restrictive reliability criteria or guides must be observed. See Available Transfer Capability.

Transfer Capability — The measure of the ability of interconnected electric systems to move or transfer power *in a reliable manner* from one area to another over all transmission lines (or paths) between those areas under specified system conditions. The units of transfer capability are in terms of electric power, generally expressed in megawatts (MW). In this context, "area" may be an individual electric system, power pool, Control Area, subregion, or NERC Region, or a portion of any of these. Transfer capability is directional in nature. That is, the transfer capability from "Area A" to "Area B" is *not* generally equal to the transfer capability from "Area B" to "Area A."

Transmission — An interconnected group of lines and associated equipment for the movement or transfer of electric energy between points of supply and points at which it is transformed for delivery to customers or is delivered to other electric systems.

Bulk Transmission — A functional or voltage classification relating to the higher voltage portion of the transmission system.

Subtransmission — A functional or voltage classification relating to the lower voltage portion of the transmission system.

Transmission Constraints — Limitations on a transmission line or element that may be reached during normal or contingency system operations.

Transmission Reliability Margin (TRM) — That amount of transmission transfer capability necessary to ensure that the interconnected transmission network is secure under a reasonable range of uncertainties in system conditions. See Available Transfer Capability.

Transmission Provider — Any public utility that owns, operates, or controls facilities used for the transmission of electric energy in interstate commerce.

Unit Commitment — The process of determining which generators should be operated each day to meet the daily demand of the system.

Voltage Collapse — An event that occurs when an electric system does not have adequate reactive support to maintain voltage stability. Voltage Collapse may result in outage of system elements and may include interruption in service to customers.

Voltage Control — The control of transmission voltage through adjustments in generator reactive output and transformer taps, and by switching capacitors and inductors on the transmission and distribution systems.

Voltage Limits

Normal Voltage Limits — The operating voltage range on the interconnected systems that is acceptable on a sustained basis.

Emergency Voltage Limits — The operating voltage range on the interconnected systems that is acceptable for the time sufficient for system adjustments to be made following a facility outage or system disturbance.

Voltage Stability — The condition of an electric system in which the sustained voltage level is controllable and within predetermined limits.

Wheeling — The contracted use of electrical facilities of one or more entities to transmit electricity for another entity.

APPENDIX B: Eight Categories of Activities

(Numbers in parentheses represent a specific "Reliability-Related Activity" as noted in Part II of this report.)

I. Load Forecasting

   A. Long Range Load Forecasting (1)
   B. Short Term Load Forecasting (11)

II. Resource Planning

   A. Generation Planning (2)
   B. Installed Adequate Reserves (3)
   C. Determine Short Term Resource plan (14)

III. Delivery System Planning

   A. Regional Transmission Planning (4)
   B. Subregional Transmission Planning (5)
   C. Individual Utility Transmission Planning (6)
   D. Distribution Planning (7)

IV. ontrol Area Services

   A. Operating Reserves (12)
   B. Provide Regulating Capability (13)
   C. Load Frequency Control (21)
   D. Voltage Control (24)
   E. Scheduling (25)
   F. Energy Imbalance (31)

V. System Maintenance

   A. Generation Maintenance (8)
   B. Transmission Equipment and Right of Way Maintenance (9)
   C. Coordination of (T&G) Maintenance Activities (10)
   D. Coordination of Transmission Equipment Construction/Maintenance (19)

VI. Resource Operations

   A. Generator Contingency Planning (15)
   B. Unit Commitment for Reliability (20)

APPENDIX C: Description of Needed Operating/Coordination Agreements and Protocols

The following operating/coordination agreements, accompanied by associated protocols, need to be developed:

(1) **Scheduling for retail service**
A scheduling agreement/protocol must be devised which facilitates the scheduling of retail transactions on the transmission system. The agreement/protocol should indicate which entities are authorized to submit schedules. These entities are likely to include (competitive) energy service providers, utility distribution companies (providing traditional utility service), load aggregators, customers with loads over a threshold size, and authorized customer scheduling agents.

The agreement/protocol should also provide rules governing the day-ahead and hour-ahead scheduling procedures and identify the obligations of the scheduling parties, including procurement of reserves, responsibility for energy imbalance charges and other ancillary services, availability for emergency communications, and settlement of accounts.

The scheduling administration function may be best assigned to an Independent Transmission Operator (ITO).

(2) **Energy schedule curtailments for transmission capacity restrictions**
When energy schedule curtailments are necessary, they should be performed on a non-discriminatory basis; that is, it is important to ensure that the transmission provider does not use its control over curtailments to disadvantage energy service providers with which it (or its parent company) competes. This agreement/protocol should specify the procedure used in making curtailment decisions.

The agreement/protocol should incorporate voluntary arrangements when possible. Parties who are willing to be interrupted in exchange for compensation should be identified. This compensation could be in the form of an interruption bid price under an ISO congestion management scheme or a discounted price for interruptible transmission service in a pre-ISO situation.

(3) **Retail transmission service terms and conditions**
Until transmission access practices and pricing design are developed to meet the objectives of Desert STAR, retail access will likely occur under modifications to existing FERC or FERC-equivalent tariffs. The design of these tariffs is a key aspect of the unbundling of retail services and will impact many of the customer-related agreements/protocols identified by the Reliability Working Group. The structural

elements of the retail transmission tariffs should be designed to be compatible with the other agreements and protocols being developed.

(4) **Energy imbalance service -- pricing, terms, and conditions**
The transmission service provider should provide energy balancing service as an ancillary service. The transmission service providers' FERC tariffs should provide ceiling prices for this service, but modifications may be necessary to make this service compatible with the nature of the new retail market structure. The agreement/protocol for billing the appropriate parties for this service should be established in conjunction with the development of Arizona's retail access scheduling agreement/protocol.

(5) **Acquisition of reserves by load serving entities providing firm service and generator contingency plans and operating agreements**
Each electric service provider providing firm capacity and energy to end-use customers must provide for the delivery of its proportionate share of the Operating Reserves required by the Control Area Operator to meet its obligations under NERC/WSCC operating criteria.

The Control Area Operator (which may be an ISO) will remain responsible for planning for generator contingencies such that all NERC and WSCC operating criteria are met. The Control Area Operator will determine reserve requirements and prepare plans for activation of reserves following specific contingencies. Contracts will have to be in place with generation providers and daily contingency plans should be coordinated with and communicated to these providers. The Control Area must have real-time control of delivery to customer loads when non-firm delivery contracts are involved.

(6) **Generator interconnection agreements -- roles, authority, and responsibilities**
Agreements should ensure compliance with WSCC/NERC reliability criteria, identify interconnection points, and specify conditions for ordering units on and off line.

(7) **Ancillary services tariff to support retail access transactions -- regulation and frequency response, voltage control from generation resources, reserve service**
The transmission service provider should provide these services as an ancillary service. The transmission service providers' FERC tariffs should provide ceiling prices for these services, but modifications may be necessary to make this service compatible with the nature of the new retail market structure. The protocol for billing the appropriate parties for regulation and frequency response and reserve service should be established in conjunction with the development of Arizona's retail access scheduling protocol.

(8) **Operation, pricing, and cost allocation for "must-run" units**
Local generating units are occasionally needed to meet local reliability requirements. To the extent competition is available to serve this need, prices will be market based. Where no competitive alternatives are available, controls may be needed to regulate prices and sale terms.

The following operating/coordination protocols, which will not require formal agreements, need to be developed:

(1) **Short-term load forecasting**
A protocol should be adopted which requires scheduling entities to provide a day-ahead load forecast to the Control Area by a certain hour each day. These load forecasts should then be provided to the Security Coordinator. For planning purposes, weekly and monthly projections should be provided by the Security Coordinator.

(2) **Long-term load forecasting**
This protocol would establish a procedure under which utility distribution companies collect load forecast data for the purpose of publishing an aggregate long-term load forecast for each respective distribution territory. This aggregate information would be available to market participants and regulators for use in evaluating anticipated load growth and the adequacy of generation supply.

(3) **Available Transfer Capability (ATC) calculation**
ATC should be calculated using a statewide standard. As part of this practice, agreement should be reached on the appropriate treatment, in a retail access environment, of transmission capacity that is currently being reserved to serve utilities' "native load" customers. The ATC calculation function may be best assigned to an ITO.

(4) **Generator maintenance scheduling**
Generation maintenance schedules should be filed with the Security Coordinator in advance, so that the Security Coordinator can ensure that necessary resources are available to maintain system reliability. A protocol should be put in place for informing/signaling generation owners that scheduling adjustments are necessary, an activity which can be incorporated into the security coordinator's oversight of operating reserves.

(5) **Public posting of transmission maintenance schedule**
An outage coordinator should be responsible for the coordination of transmission and generation maintenance activities. Transmission maintenance schedules should be submitted to the Security Coordinator and should be posted well in advance, to provide market participants an opportunity to adjust. The outage coordinator should have final authority over planned outage schedules.

(6) **Coordination in performing transmission operating studies**
The Security Coordinator should be responsible for coordinating transmission operating studies in order to mitigate the potential difficulties in establishing the accuracy of operating studies in a competitive environment. Mechanisms should be developed to accomplish coordination between generation owners and transmission owners (and possibly other stakeholders).

(7) **Posting of real time market information for transmission and ancillary services supporting retail access transactions (OASIS)**
This function may be appropriate for an ITO.

APPENDIX D: Schedule For Development of Agreements and Protocols

Agreements	Start Date	Completion Date
1) Scheduling For Retail Service	December 1997	June 1998
2) Energy Schedule Curtailments for Transmission Capacity Restrictions	February 1998	June 1998
3) Retail Transmission Service Terms And Conditions	December 1997	June 1998
4) Energy Imbalance Service	March 1998	July 1998
5) Acquisition of Reserves	March 1998	July 1998
6) Generator Interconnection Agreements: Roles, Authority, and Responsibilities	June 1998	September 1998
7) Ancillary Services Tariff	March 1998	July 1998
8) Must-Run	April 1998	September 1998

Protocols	Start Date	Completion Date
1) Short-Term Load Forecasting	February 1998	September 1998
2) Long-Term Load Forecasting	July 1998	September 1998
3) ATC Calculation	April 1998	June 1998
4) Generator Maintenance Scheduling	June 1998	September 1998
5) Public Posting of Transmission Maintenance Schedule	June 1998	September 1998
6) Transmission Operating Studies	August 1998	September 1998
7) OASIS	April 1998	June 1998

APPENDIX E: List of Working Group Members and Participants

The following organizations and their representatives participated in the Reliability and Safety Working Group meetings:

ABCO Foods: Dennis Julian

Arizona Community Action Association: Betty Pruitt

Arizona Consumers Council: Barbara Sherman

Arizona Electric Power Cooperative, Inc.: Larry Huff, Bruce Evans, Randall Welker

Arizona Municipal Power Users Association: Michael Curtis, Thomas Hine

Arizona Public Service Company (APS): Jack Davis, Cary Deise

Arizona Utility Investors Association: Bill Meek

BHP Copper: Eli Knezovich, Andrew Gregorich

Calpine Corporation: Mike Rowley

Citizens Utilities Company: Resal Craven, Dennis True, Paul Townsley

Cyprus Climax Metals: Mike McElrath

Destec Energy/NGC Corp.: Barry Huddleston

Electric Competition Coalition: Douglas C. Nelson

Energy Strategies Inc.: Kevin Higgins

Enron: James Tarpey, Leslie Lawner, Tom Delaney, Janel Guerrero, Mona Petrochko, Lyndon Taylor

Goldwater Institute: Michael Block

K.R. Saline & Associates: Dennis Delaney, John Ault

Institute of Electrical and Electronics Engineers, Inc. (IEEE): Richard Farmer

Intel: Marty Sedler

International Brotherhood of Electrical Workers (IBEW): Tom Gallagher, Mike Fox

Land and Water Fund of the Rockies: Rick Gilliam

Mesa, City of: John Branch

Mohave Electric Cooperative: Stephen McArthur

Nordic Power: A.B. Baardson

Phoenix, City of: Bill Murphy

Residential Utility Consumer Office (RUCO): Steve Gibelli, Greg Patterson, Teena Wolfe

Safford, City of: Kenneth Mecham

Smith's Foods: Mick Meeks

Salt River Project (SRP): David Murphy, John Underhill

Tempe, City of: Harvey Friedson

Tucson, City of: Linda Buczynski, Ron Ballard

Tucson Electric Power Company: Mike Raezer

Western Area Power Administration (WAPA): J. Tyler Carlson, Robert Easton, Chuck McEndree, John Randall, Tony Montoya

Western System Coordinating Council (WSCC): Robert Dintleman

Staff Support:

Arizona Corporation Commission Staff Support: Gary Smith, Prem Bahl, Matt Rowell, Ray Williamson